BDR

A Gestalt Company

Exhibit H

Cost Comparison of Generation and Transmission Alternatives in Northern York Region

For

The Ontario Power Authority

September 23, 2005

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1 EXECUTIVE SUMMARY

The technical advisors selected by the OPA to assist in resolving electricity supply planning issues in northern York Region have indicated that if a generator of sufficient capacity were to be constructed, the necessity for additional transmission capacity in the region could be deferred, and perhaps eliminated for the foreseeable future. In order to bring a complete recommendation to the Ontario Energy Board in this matter, the OPA retained Barker, Dunn & Rossi ("BDR"), A Gestalt Company, to assess the relative financial costs and benefits to Ontario electricity ratepayers that would result from the choice to build generation and/or transmission capacity in northern York Region.

For the analysis, BDR used generator configurations, operating characteristics and costs, and transmission project costs as identified by the technical advisors retained by the OPA for northern York Region. In assessing the incremental costs to ratepayers of generation, BDR assumed that new gas-fired generation would be required to be built in Ontario by 2011, and that therefore the scenarios for comparison are:

- Build a generator of sufficient capacity at a location in northern York Region, in which case transmission capacity would not have to be expanded for the foreseeable future (minimum 20 years); or
- Serve the incremental needs of northern York Region from generation built outside York Region, and provide incremental transmission capacity into northern York Region by 2011.

Annual costs of the incremental transmission to serve northern York Region were computed by applying a rate base/rate of return approach to the estimated capital cost. The requirements of a generation investor to recover fixed and variable annually, over the life of the project, were also computed. To compute variable costs, a model was developed to compare the hourly electricity spot market price to the plant's variable costs of production, based on historic natural gas prices and estimated plant heat rate. Incremental transmission losses were also considered where applicable, by applying a loss percentage to the total market cost of generated electricity. Since the cost of natural gas supply was assumed to be affected by the generator's location, the number of hours of market operation was different; to make scenarios comparable, the assumed level of production of the generator outside York Region was reduced, and the corresponding variable costs were reduced. Generator activity in the operating reserve market was ignored, since the revenues could be assumed to be the same for the same generator configuration, whether located in northern York Region or outside York Region.

The overall cost to consumers was computed by taking present value of annual net cash flows payable by consumers for the fixed costs and variable operating costs of the generator, and for the transmission project in scenarios where new transmission was assumed to be constructed.

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The following table summarizes the results for two simple cycle generator configurations, using three assumptions for the capital cost of transmission. The assumption of $23 million assumption reflects the technical advisors' capital cost estimate of the recommended Buttonville-Gormley option, with all overhead construction, as detailed in Exhibit D. The assumption of $18.5 million reflects the same construction option, but assumes that it could be constructed with a 20% saving from estimated cost. The third scenario of $67 million reflects the same transmission route, with all underground construction, including $60 million for underground cable installation plus $7 million for dismantling the existing 115 kV line, also as set out in Exhibit D.

PV of Net Saving to Customers Resulting from Generator in Northern York Region, as Compared with Generation Outside York Region Combined with Transmission

	PV of Savings Over 20 Years, Assuming 5% Discount Rate	
Transmission Capital Cost 2005 Price Levels	**Simple Cycle 5 x LM6000PD**	**Simple Cycle 2xGE PG7241FA**
$18.5 million	$33.9 million	$35.3 million
$23 million	$38.3 million	$39.7 million
$67 million	$82.1 million	$83.5 million

In all cases, comparing the same generator configuration in northern York Region and outside York Region, it is less costly to consumers to build the generator in northern York Region and avoid both the costs associated with construction of the transmission line and transmission losses. It can be concluded that no transmission option of $18.5 million or more in capital cost would be economic, as compared with the construction of generation in northern York Region.

The study considered only the financial impacts on consumers through electricity rates. No environmental or health impacts, nor external economic impacts such as job creation or property value impacts were considered.

These results should not be used to support a decision as to the type of generation that should be built in York Region.

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2 INTRODUCTION

In April, 2005, the Ontario Power Authority ("OPA") engaged Barker, Dunn & Rossi ("BDR") as part of a legal and consulting advisory team to assist with arranging contracts for generation facilities and/or verifiable load deferral activities in the north-eastern area of York Region. The contract or contracts would be conditional on the ultimate approval of the Ontario Energy Board (OEB) and would be entered into by the OPA to establish the feasibility of generation and/or load deferral as a solution to the need for reinforcement of the bulk electricity supply in northern York Region. As part of this process, on May 2, 2005 the OPA issued two Requests for Expressions of Interest – one for Verifiable Demand Reduction and one for New Generation Facilities. The responses received supported the conclusions that:

- Multiple and diverse opportunities have been identified with potential to deliver demand reductions in northern York Region, and which deserve further consideration; however, demand reduction alone, without new generation or transmission facilities, would not be sufficient as a solution to northern York Region's supply issue; and
- Several private sector parties are willing to develop and operate new generation at a suitable location to meet requirements, provided that acceptable contract terms can be reached with the OPA.

The technical advisors selected by the OPA to assist in this regional planning issue indicated that if a generator of sufficient capacity were to be constructed, the necessity for additional transmission capacity in the region could be deferred, and perhaps eliminated for the foreseeable future. Having confirmed that generation represented a possible technical solution in northern York Region, the OPA was faced with the question of the relative costs of the available alternatives, or combinations of alternatives. In fulfilling its requirement to bring forward a recommendation to the Ontario Energy Board ("OEB"), the OPA needed to be able to address not only the technical issues of supply adequacy and reliability, and acceptability to the community, but also the cost burden which the recommended solution would place upon Ontario electricity ratepayers, whether inside or outside of northern York Region.

The OPA therefore requested BDR, working with OPA staff and the technical advisors, to develop an analytical framework to compare the costs of generation and transmission options, and using cost data provided, to determine the relative costs of the options.

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3 CONSULTANT QUALIFICATIONS

BDR is a leading management consulting firm specializing in advising the North American and international electricity industry on matters related to emerging, evolving and developed electricity markets. Our clients are found throughout the world and include entities such as governments, regulators, market participants, consumers, generators, transmission companies, and distribution utilities. BDR's Ontario-based consultants have been involved in the electricity sector for many years, both as consultants and in management positions within sector participant organizations and the financial community.

Key dimensions of BDR' s practice include business planning and advisory services; mergers, acquisitions and valuations; pricing and cost analysis. We have advised numerous clients who are, or are considering becoming, owners of generation, transmission, and distribution resources in Ontario. Our clients also include the Government of Ontario and the Ontario Energy Board. Recent assignments include involvement in a response to Ontario's RFP for 2,500 MW of generation and demand response resources.

BDR has recently become a member of the Gestalt corporate family. Gestalt, LLC is a business and information technology consulting and services firm specializing in the application of interoperation technologies including automation technologies, decision support and simulation in both the United States Department of Defense (DoD) and utility industries. Gestalt has built a reputation for developing innovative technology solutions and rapidly delivering business value by leveraging both industry specific domain and deep technology experience.

The BDR team responsible for assistance to the OPA with respect to solutions in York Region includes John McNeil, President, and Paula Zarnett, Vice President of BDR.

John is a member of the Board of Directors of Atlantic Power Corporation , a publicly traded income fund with significant investments in the power generation business. He has also been a member the electricity task force of the Toronto Board of Trade for the past ten years. John's diversified experience includes working with both public and private sector entities as owners of energy businesses in terms of policy, ownership and valuation of the various options open to them. He has advised many generators as to their practical opportunities in terms of new build, expansion, buy/sell, use of different fuel sources negotiating appropriate power purchase agreements , and financing. John's related assignments include:

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- Acted on behalf of a local/regional consortium of interested potential purchasers in the assessment of the appropriate valuation, financing and bidding strategies with respect to generation facilities located at Atikokan and Thunder Bay Ontario.
- Assisted the City of Edmundston in assessing options and developing a strategic business plan to address the challenges to its municipal electric utility in the context of New Brunswick electricity restructuring, including matters related to generation owned by the utility.
- Advised Hydro Ottawa regarding options and indicative values for its totality and component parts, including its generation business unit.
- Developed an industry overview assessment for PetroCanada in assessing the feasibility of developing generation in Ontario.
- Assisted PetroCanada in identifying and assessing potential developer/partners for Ontario generation projects.

Paula has 25 years of experience in the Canadian electricity and gas sector. Formerly a manager at Toronto Hydro with responsibility for pricing designs, load forecasting and load research, and previously an analyst with those functions, Paula has extensive experience in the analysis of hourly load data. In that capacity, she participated in a number of initiatives to analyze the feasibility of generation projects, and developed financial models to support a long-term distribution system upgrade plan. She was also responsible for assessing the value of potential curtailment (load deferral) arrangements with customers and developing related incentive pricing.

Paula's recent relevant consulting assignments include:

- financial modeling of a hydro generation business unit, including a proposed expansion for Hydro Ottawa;
- financial and operational modeling for a response to the recent Ontario RFP for 2,500 MW of new generation or demand response capacity;
- industry overview and analysis for PetroCanada in assessing the feasibility of developing generation in Ontario.
- analysis of impacts on transmission rates that might result from undergrounding a component of transmission lines on behalf of the Town of Markham;
- analysis and expert testimony with regard to gas distribution rates applicable to Ontario gas-fired generators.

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4 SCOPE OF THE ASSIGNMENT

The scope of the assignment was to compare the financial impacts of supply options for northern York Region, each of which might consist of additional transmission capacity, additional generation capacity, or both. As stated in the Introduction, it had been concluded that although demand reduction options existed and were considered desirable, these would not be sufficient alone as a solution to northern York Region's supply issues in the long term. For purposes of the analysis, therefore, it was assumed that decisions with respect to implementation of demand reduction programs would be taken independently of decisions with respect to transmission and generation.

Determination of the technically feasible supply option alternatives, and their timing, was the responsibility of OPA's technical advisors for the York Region project. The technical advisors provided, in the course of extensive discussions with BDR and with OPA staff, descriptions of the alternatives and the costs associated with each. BDR developed, based these discussions and data, our experience, and elements of the evaluation approach used in the Government's recent 2,500 MW CES RFP, a series of spreadsheet-based analytical models. The approach and assumptions were reviewed in meetings with OPA staff, the technical advisors, and Ministry of Energy staff, and were presented at a meeting of the York Region Supply Issues Working Group in July, 2005. BDR used its models to complete the analysis, and prepared this report based on the results.

5 METHODOLOGY

5.1 *General Approach and Assumptions*

The starting point for the assignment was to frame an appropriate definition for the alternative supply options to be analyzed and compared.

Northern York Region is a growing community, and will have a requirement for additional supply capability that cannot be expected to be completely offset by demand reduction, even if supported by aggressive programs. To bring the required supply from outside northern York Region, additional transmission capacity would be required. The OPA's technical advisors informed BDR that the capital cost of such additional transmission would range between $23 and $115 million dollars at current levels of cost. It is also important to consider that the electricity demand of Ontario as a whole, including northern York Region and other communities, will require new generation to be built over the next several years. At least some of this new generation will be gas fired. If additional transmission capacity is built to serve northern York Region, then the

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electricity to supply northern York Region's growing requirements could come from existing and new generation located anywhere in Ontario.

Possible sites for new gas fired generation exist in northern York Region. If a generation plant of sufficient size were built at a technically suitable location in northern York Region, then northern York Region's additional requirements could be served without additional transmission capacity. Such a generation plant in northern York Region would be part of the overall generation capacity in Ontario, and would therefore ***substitute for*** a generation plant of the same approximate size and type elsewhere in the province.

The OPA's technical advisors informed BDR that if a generator with a minimum level of 140 MW of capacity, which would reliably be available at periods of summer peak demand, could be built in York Region and connected to the grid in the specified location, additional transmission capacity would not be required for the foreseeable future. BDR was also informed that there are no technical impediments to the connection of either a simple cycle plant or of a combined cycle large enough to benefit from efficiencies of scale (more than 500 MW).

According to the technical advisors, some supply option will be required to be in place by the year 2011. There are essentially two categories of supply option alternatives:

- New transmission capacity is constructed in northern York Region, which will bring electricity supply from generation outside northern York Region; or
- New generation is built at a suitable location within northern York Region, and ***no*** new transmission capacity is required in northern York Region for the foreseeable future.

Within these broad categories of alternatives, various options exist as to the type and size (and therefore the cost) of either generation or transmission plant.

5.2 *Definition of General Assumptions*

In all scenarios, it was assumed that the generation option would be a gas-fired unit. This assumption is considered reasonable because:

- it is expected that most of the new generation capacity built in Ontario in the next few years will be gas-fired;
- gas-fired plants have fewer special requirements as to location than most other types, can could be built in northern York Region; and
- lead times for a gas-fired plant are short enough that a new one could be in service before the required date of 2011.

In response to the Request for Expressions of Interest for New Generation in York Region ("RFI") mentioned in the Introduction, suggestions for both simple cycle and combined cycle plants were received. Since the technical advisors indicated that there is

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no technical barrier to the construction and connection of an efficient size combined cycle plant, both of these options deserve consideration. Since no specific project has been designed and selected, the OPA requested the technical advisors to define plant configurations that were representative of simple and combined cycle plants, and to provide reasonable assumptions about their cost and operating characteristics. This information was provided to BDR for its analysis.

Each configuration therefore resulted in a matched pair of scenarios: one in which a generator is built in northern York Region and no additional transmission capacity is required, and one in which a generator is built outside northern York Region, and its output made available to northern York Region through new transmission capacity. Since the technical advisors indicated that each of the configurations could be built at the same cost, and operate at the same efficiency inside northern York Region as outside northern York Region, comparisons in the analysis are made holding constant the capital, operating costs and operating characteristics (start-up costs and heat rate) whether inside or outside of York Region. Therefore only one cost distinguishes the generators in each pair of scenarios, and that is the cost of natural gas supply to the plant. It was assumed that if the generator is outside northern York Region, it would be built where gas supply costs are lowest, close to the Dawn Hub in the Sarnia area. Estimates of the incremental cost of gas delivered in York Region, as compared with Dawn, were obtained from stakeholders and others. To be conservative in the analysis, the highest estimate obtained was utilized.

5.3 *Transmission Assumptions*

Three transmission capital cost scenarios were utilized in the analysis. The assumption of $23 million assumption reflects the technical advisors' capital cost estimate of the recommended Buttonville-Gormley option, with all overhead construction, as detailed in Exhibit D. The assumption of $18.5 million reflects the same construction option, but assumes that it could be constructed with a 20% saving from estimated cost. The third scenario of $67 million reflects the same transmission route, with all underground construction, including $60 million for underground cable installation plus $7 million for dismantling the existing 115 kV line, also as set out in Exhibit D. All three scenarios were run; however, it is noted that if transmission is shown not to be economic at the lowest of these capital cost levels, it will not be economic at any higher cost level.

The technical advisors also modeled the effects on the Ontario transmission system of adding generation capacity in northern York Region, as compared with adding capacity in the Sarnia area. It was determined, and advised to BDR that generation capacity in the Sarnia area would result in technical losses of approximately 7% of all kWh generated. These losses are therefore an incremental cost that would result if the new generation is outside northern York Region and transmission capacity is added.

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5.4 *Scenario Summary*

The following table summarizes the characteristics which distinguish each scenario modeled.

	Simple Cycle in York Region		Simple Cycle Dawn Location		Combined Cycle Inside York Region	Combined Cycle Dawn Location
Representative Plant Configuration	5 x LM6000PD	2 x GE PG7241FA	5 x LM6000PD	2 x GE PG7241FA	GE 7241FA 2x1	GE 7241FA 2x1
Capital Cost						
Best Estimate (+/- 20%)	$ 149,000,000	$ 147,000,000	$ 149,000,000	$ 147,000,000	$ 450,000,000	$ 450,000,000
Summer Capacity (MW)	195	297	195	297	524	524
Fixed O&M per year	$ 900,000	$ 900,000	$ 900,000	$ 900,000	$ 7,860,000	$ 7,860,000
Variable O&M per MWh	$ 3.50	$ 3.50	$ 3.50	$ 3.50	$ 2.70	$ 2.70
Start Up Cost (MMBTu)	95	580	95	580	2000	2000
Heat Rate	9,230	9,928	9,230	9,928	6,100	6,100
Gas Pricing Increment from Dawn $/GJ	$ 0.23	$ 0.23	$ -	$ -	$ 0.23	$ -
First Year of Generator Operations	2011	2011	2011	2011	2011	2011
Year Transmission Required	Never	Never	2011	2011	Never	2011
Transmission Capital Cost - A	N/A	N/A	$ 23,000,000	$ 23,000,000	N/A	$ 23,000,000
Transmission Capital Cost - B	N/A	N/A	$ 67,000,000	$ 67,000,000	N/A	$ 67,000,000
Incremental Transmission Losses as Percent of Generation Output	0%	0%	7%	7%	0%	7%

5.5 *Modeling Approach Overview*

The modeling approach is a discounted cash flow analysis of the costs of each combination of supply options, summarized as the net present value of the difference in incremental costs for 20 years.

The intention of the modeling approach was to compare, over the expected life of a gas-fired generator (assumed to be 20 years), the financial cost that would be borne by electricity consumers in Ontario as a result of the various supply options. The analysis makes no assumption as to whether costs would be recovered from customers within York Region or outside it; nor is there any distinction made between types of electricity-related charges to consumers (such as transmission charges, spot market prices, or other energy costs such as the costs of contracts between generators and the OPA). The analysis is a simple computation and discounting of total annual costs that would result from the option and need to be recovered from customers through charges in the year. For simplicity, the effects of the regulated pricing plan, which smooths the costs of generation to some customers, are not modeled; it is assumed that the market price for generation is borne by consumers in the year incurred.

Since the point of view is electricity customers, cash flows start at the time the transmission and/or generation facilities come into service and start to earn a revenue, rather than at the time the transmission or generation provider makes the capital investment.

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Costs as incorporated in the model include only quantifiable financial costs directly related to electricity use. Excluded are:

- broader economic costs and benefits such as job creation or impacts on property values;
- environmental and health impacts; and
- aesthetic, convenience or quality of life impacts.

6 ANALYSIS

6.1 *Specific Modeling Approach*

6.1.1 Transmission

To convert the capital cost of a potential transmission project to an annual cash flow over a period of time, a model was constructed that would compute a "revenue requirement" for the project on the basis of the framework used by the Ontario Energy Board to compute overall allowed rates to transmission companies. The new capital investment is assumed to be financed based on the capital structure currently approved for Hydro One, and a nine percent regulated rate of return on equity. Allowed net income is computed by multiplying the total amount remaining invested in the year (net of accumulated depreciation) by the allowed equity ratio, and then by the allowed return on equity. The income tax attracted by this income is then estimated. Interest expense is computed using the debt ratio in the capital structure and a reasonable interest rate under current conditions.

To this we add depreciation expense, which has been estimated using a 40-year assumed life for the assets. Operating, maintenance and administration expenses would ordinarily be included also, but are assumed to be insignificant on an incremental basis. These costs are summed to produce a total cost to be paid in the transmission rates each year. Since the net level of investment, or "rate base" declines each year as the assets depreciate, the total revenue requirement would decrease gradually to zero over a 40-year period. As stated in the previous section, no assumption was made as to whether the costs would be absorbed in the network rates for transmission in the province, or whether they would be assigned for recovery from customers within York Region.

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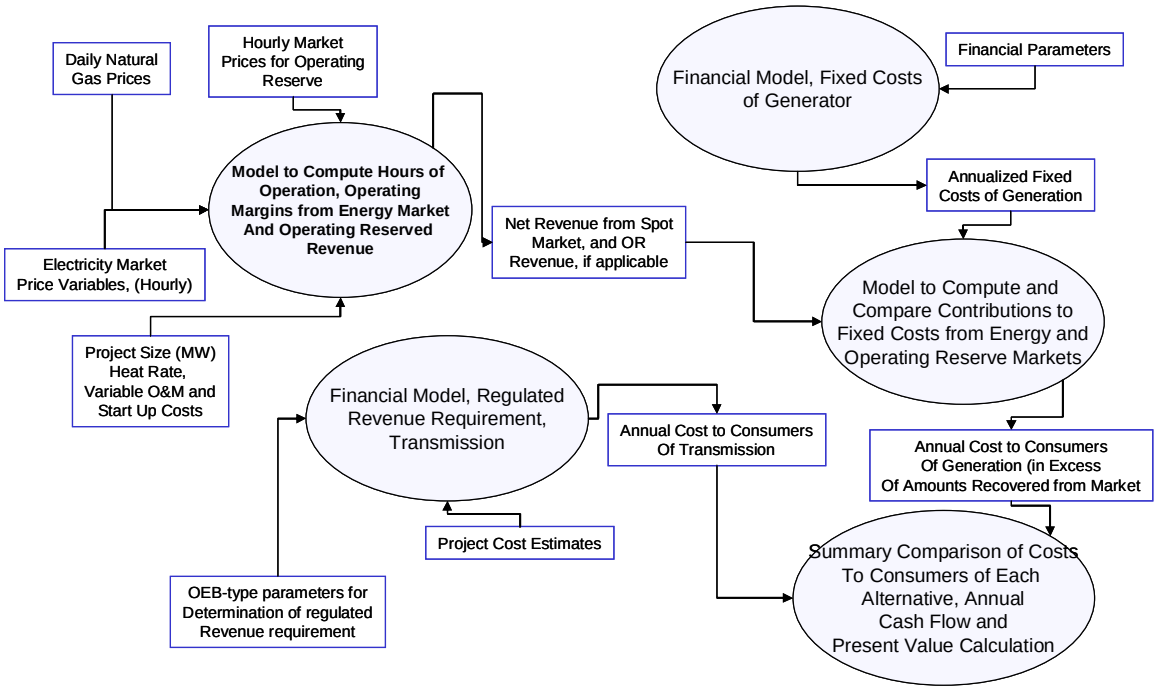

6.1.2 Generation

A model was developed to compute the cash flow requirements, over a 20-year project life, that are assumed to be required to give the generation investors an adequate rate of return. It was assumed that a suitable contract arrangement would be entered into by the OPA with a generator, thus limiting the level of business risk to the generation investors, and that therefore investors would be willing to build the plant in expectation of an equity rate of return of 12 percent. A stream of cash flows was then developed, assuming that the initial investment of funds would take place over a two-year period (2009 and 2010), and that the generator would commence operating and receiving revenue in 2011, at the time when needed in northern York Region. Investors (both equity and debt) were assumed to be repaid in a simple straight line manner over 20 years, as the assets are depreciated for financial purposes, resulting in a declining requirement for interest and equity return over time.

A net present value and internal rate of return from these cash flows was computed. From this, a series of annual payments was computed having the same net present value,

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discounted at the internal rate of return, which would be level for 80% of the amount, and increase by 2% annually for 20% of the amount. This mirrors the payment stream proposed for generators under the recent 2,500 MW CES contracts. An annual revenue requirement to cover the generator's fixed investment-related and operating costs could thus be computed and compared among the generation projects modeled. This revenue requirement represents the fixed cost of the generation option for modeling and comparison.

Variable costs are assumed to be the costs of delivered natural gas, variable O&M, and start-up costs for the actual hours in which the generator is in production.

It was assumed that the generator would operate in all hours in which variable fuel and operating costs could be recovered in the Hourly Ontario Electricity Price. This required the operation of the generator in the spot market to be modeled. The model uses historic natural gas and electricity spot market prices for the period August 1, 2002 through July 31, 2004, along with the specific project heat rates, start up costs and variable operating costs to compute an hourly variable cost of generation. The generator is assumed to start and cease operation according to certain rules which compare the variable costs with the pre-dispatch price and/or the Hourly Ontario Electricity Price. Generally, the generator will operate when a positive contribution to fixed costs can be realized; the more efficient the generator and the lower its variable costs, the more often it will operate in the spot market.

Variable cost in each hour of operation was computed using the gas price, heat rate, variable O&M cost, and start-up cost figures provided by the technical advisors for each generator configuration.

In developing the analysis, consideration was given to the revenue effects of the operational requirement on a generator in northern York Region to run in response to peak hour supply reliability issues in the region. For simplicity it was assumed that reliability must-run requirements would occur in the system peak hours of summer and winter, when the spot market would most likely result in a price-based signal to the generator to operate. On this basis, it was assumed that the impacts of reliability must-run requirements would not have significant impacts on either the number of operating hours or the operating revenue from the market.

In discussions, interested generation investors have suggested that revenues from the operating reserve market be considered as a source of reduction in the incremental payment obligations of the OPA to contract generators. Since the operational model identifies the specific hours of operation of the generator, and the historic hourly operating reserve revenues (10 minute non-synchronous) are known, the maximum potential revenue from this source can be computed by assuming that operating reserve revenue is earned in every hour when the generator is not dispatched in the energy

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market. All possible operating reserve revenue scenarios would therefore be bracketed by this maximum scenario and a zero scenario. While the ability to achieve revenues from the operating reserve market does affect the economic business case of a generator, and is important in comparing generator configurations, a decision was made to exclude operating reserve revenues from this analysis. The potential for OR revenues was not indicated to be different when comparing the same generator configuration in northern York Region as compared with outside York Region, except for the effect of different hours of operation in the energy market. Since it was necessary to adjust the hours of operation to the same level for each location in order to make scenarios comparable, this difference disappears. As a result, OR revenue does not affect the comparison of location scenarios, and was therefore excluded from consideration.

Incremental transmission losses are also a factor in differentiating the costs of a generator located in northern York Region as compared with the same generator configuration at a location near Sarnia. The technical advisors provided BDR with an estimate of incremental transmission losses of 7% of the generator's production. This cost is therefore included in the analysis as a cost of generation outside northern York Region.

The total cost of generation to consumers under each scenario was therefore the sum of the variable cost of energy production, incremental losses where applicable, and annualized fixed costs.

6.1.3 Overall Comparison of Supply Options

Each supply option was therefore considered to involve some new generation, whether inside or outside York Region. If the generator is constructed in northern York Region, it is assumed that no incremental transmission capacity in northern York Region would be required in the foreseeable (modeled) future; if the generator is constructed outside northern York Region, new transmission capacity would be required in 2011.

Supply options consisting each of generation, plus transmission where applicable, were modeled over 20 years, commencing in 2011, by adding together, in each year, the incremental costs to electricity consumers resulting from the options.

In order to compare among scenarios with generators of different capacities and efficiencies, and therefore different production, the variable cost of production in all "outside York Region" scenarios was adjusted downward to assume the same operating hours as the northern York Region scenario.

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6.2 *Analysis Results*

6.2.1 Generator Operations and Variable Costs

The following table sets out the results of running the operating model for each of the six generation configurations. As anticipated:

- The lower heat rate of the combined cycle plant configurations resulted in significantly more hours of operation than for the simple cycle plants; losses therefore have a higher impact in comparing the combined cycle scenarios.
- For each combination of generator configurations, the "northern York Region" scenario yielded fewer operating hours and lower margins from the spot market. This is because the location, away from the Dawn gas hub, is assumed to result in higher unit costs for natural gas.
- As explained in Section 5, operating reserve market revenues were considered to have no effect in comparing configuration pairs of generation options and were therefore excluded from the computation.

INPUTS	Simple Cycle in York Region		Simple Cycle Dawn Location		Combined Cycle Inside York Region	Combined Cycle Dawn Location
Generator Configuration	5 x LM6000PD	2 x GE PG7241FA	5 x LM6000PD	2 x GE PG7241FA	GE 7241FA 2x1	GE 7241FA 2x1
Capital Cost	$ 149,000,000	$ 147,000,000	$ 149,000,000	$ 147,000,000	$ 450,000,000	$ 450,000,000
Fixed Operating Cost per Annum	$ 900,000	$ 900,000	$ 900,000	$ 900,000	$ 7,860,000	$ 7,860,000
Capacity (MW)	195	297	195	297	524	524
Variable O&M per MWh	$ 3.50	$ 3.50	$ 3.50	$ 3.50	$ 2.70	$ 2.70
Start Up Cost (MMBTu)	95	580	95	580	2000	2000
Heat Rate	9,230	9,928	9,230	9,928	6,100	6,100
Gas Pricing Increment from Dawn $/GJ	$ 0.23	$ 0.23	$ -	$ -	$ 0.23	$ -
Incremental Transmission Losses as Percent of Generation Output	0%	0%	7%	7%	0%	7%
OUTPUTS						
Avg Running Hours/Month	174	123	196	143	383	394
Avg Paid Start-Ups Per Month	18	14	19	16	26	26
Average Monthly Contribution to Fixed Costs from the Energy Spot Market	$ 2,889	$ 2,237	$ 3,133	$ 2,469	$ 7,960	$ 8,435
Average OR Revenue Per Month, Assuming Maximum Sales in OR Market	$ 1,913	$ 2,199	$ 1,810	$ 2,107	$ 682	$ 639
Avg Incremental Transmission Losses Per Month	$ -	$ -	$ 229,241	$ 271,586	$ -	$ 1,021,947
Avg Gross Market Revenue per Annum	$ 35,939,495	$ 41,565,151	$ 39,298,411	$ 46,557,527	$ 171,933,730	$ 175,190,953
Avg Variable Cost of Operation, per Annum	$ 29,179,256	$ 33,592,381	$ 31,967,817	$ 37,757,518	$ 121,880,032	$ 122,152,970

6.2.2 Generator Fixed Cost Requirements

In reality, the ability of the generation proponent to finance the project at low cost will be part of the competitive advantage of a particular project, such considerations will distort the purely technical comparison of locations inside and outside northern York Region.

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Therefore, in this analysis, all generation projects were assumed to face identical capital structure and cost requirements:

- a 65/35 debt/equity structure
- 5.5% interest
- 12% rate of return for the equity investor, and
- a tax rate of 36.1%
- annual increases in construction and operating costs, 2%.

Although it is anticipated that a generation project could be constructed and commence operations earlier, it was assumed for modeling purposes that all projects would be constructed over a two-year period (2009 and 2010), and commence operation in 2011, at the time when York Region load is forecast to require them. Costs were assumed to escalate by 2% annually from their starting values.

The projects were distinguished only by their capital cost and their fixed operating costs. All differences reflect the plant configurations identified by the technical advisors. No differences in fixed costs were assumed to result from location.

Following the precedent of the 2,500 MW CES RFP, it was assumed that generators would be required to bid an annual revenue requirement, to be recovered through a combination of market revenue and payments from the OPA, on the basis of 80% levelized over a 20-year term, and 20% escalating by 2% annually. A computation was therefore made to determine the stream of payments on this basis that would be equivalent on a present value basis, discounted at the project IRR of 7.6%, to the annual costs of the project, including return of capital and return on capital to the investors.

The following table shows the results:

Generator	Total Capital Cost 2005 Price Level	Annual Fixed Operating Cost 2005 Price Level	Capacity (MW)	Annual Net Revenue Required 2011
Simple Cycle 5 x LM6000PD	$149,000,000	$900,000	195	$18,731,000
Simple Cycle 2 x GE PG7241FA	$147,000,000	$900,000	297	$18,496,000
Combined Cycle 2 x GE 7241FA	$450,000,000	$7,860,000	524	$63,169,000

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6.2.3 Costs of Transmission

It was assumed that the cost to Ontario ratepayers of transmission would be determined annually on a regulated revenue requirement basis, and that these costs, in scenarios where transmission is required to be built, would commence in 2011. Capital cost scenarios of $23,000,000, $18,500,000 and $67,000,000 based on 2005 cost levels, and escalated by 2% annually to 2011 levels were assumed, based on the recommended Buttonville-Gormley transmission option detailed in Exhibit D.

The following table shows the computations of the revenue that would be required from electricity ratepayers during the first three years that the transmission line is in service, assuming a $23,000,000 capital cost. The line is computed to impose slightly more than $2.9 million of costs annually on this basis in 2011; as the funds are repaid to investors and rate base declines, the annual costs decline toward zero over the assumed 40 year life of the assets.

Transmission Annual Rate Base and Revenue Requirement

Total Capital Cost 2005 Dollars	$23,000,000
Start Year	2011
Preferred Equity	4.0%
Common Equity	36.0%
Return on Prefered Equity	5.5%
Project Life	40
Debt Rate	5.5%
Regulated Return on Equity	9.0%
Debt Ratio	60.0%
PILS Rate	36.1%
Inflation	2.0%

		2011	2012	2013	2014
Total Capital Invested in Start Year		$25,901,736	$25,254,192	$24,606,649	$23,959,105
Debt Component		$ 15,541,041	$ 15,152,515	$ 14,763,989	$ 14,375,463
Preferred Equity		$1,036,069	$1,010,168	$984,266	$958,364
Common Equity		$9,324,625	$9,091,509	$8,858,394	$8,625,278
Interest		$854,757	$833,388	$812,019	$790,650
Preferred Return (AT)		$56,984	$55,559	$54,135	$52,710
Common Return (AT) (Using Regulated Return)		$839,216	$818,236	$797,255	$776,275
Depreciation		$647,543	$647,543	$647,543	$647,543
PILS		$506,304	$493,646	$480,989	$468,331
Incremental OM&A		$0	$0	$0	$0
Annual Revenue Requirement		$2,904,805	$2,848,373	$2,791,942	$2,735,510
NPV at WACC in Start Year	$34,717,284	$2,904,805	$2,848,373	$2,791,942	$2,735,510
NPV at WACC in 2005	$ 25,080,414				

WACC	Percentage	Rate	Tax	Net	Product
Debt	60.0%	5.5%	36%	3.51%	2.11%
Preferred	4.0%	5.5%		5.50%	0.22%
Common	36.0%	9.0%		9.00%	3.24%
WACC					5.57%

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6.2.4 Summation of Generation and Transmission Costs for Comparison

Each supply option scenario therefore assumed 20 years of net incremental costs (or benefits) associated with the generator commencing operations in 2011, combined with the costs of transmission commencing in 2011 in the scenarios in which transmission would be required to be built.

No explicit assumption was made as to the supply strategy after 2030, and no terminal value was assumed for the transmission assets.

Tables setting out the computations for each of the three generator configurations are included in the Appendix.

The following table shows the summary net present values of the difference in costs to consumers of each configuration, in 2005 dollars, computed at both a 5% and a 7% discount rate, reflecting the three transmission capital cost scenarios:

		PV of Net Saving to Customers Resulting from Generator in Northern York Region, as Compared with Generation Outside Northern York Region Combined with Transmission $ Million		
Transmission Capital Cost	**Discount Rate**	**Simple Cycle 5 x LM6000PD**	**Simple Cycle 2xGE PG7241FA**	**Combined Cycle GE7241FA 2x1**
$18.5 million	5%	33.9	35.3	84.5
	7%	25.8	26.8	63.8
$23 million	5%	38.3	39.7	89.0
	7%	29.2	30.2	67.2
$67 million	5%	82.1	83.5	132.7
	7%	62.9	63.9	100.8

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7 CONCLUSIONS

The computations show that regardless of generation configuration, Ontario consumers are better off in terms of electricity costs if generation can be built in northern York Region, and thus eliminate the need for incremental transmission capacity in the Region for the foreseeable future.

Note that in this analysis, no consideration was given to the value of environmental or health impacts of any scenario, nor to external economic impacts such as property values or job creation.

It is ***not*** recommended that this analysis be used as a basis to decide whether a simple cycle or a combined cycle plant should be built at any specific location inside or outside northern York region; the wider needs of the Ontario electricity system should be considered in such a decision.

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APPENDIX H-1
Comparison of Generation and Transmission Scenarios

Transmission Capital Cost: $23 Million
Discount Rate: 5%

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Simple Cycle Plant - 5 x LM6000PD

Capital Cost, 2005 Dollars	$ 149,000,000	
Fixed Operating Costs, 2005 Dollars	$ 900,000	
BUILT IN NORTHERN YORK REGION		
Contribution to Fixed Costs from Market (2002-2004 Prices)	$ 2,889	per MW per month
Plant Capacity	195	MW
Annual Production	408,038	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$ 6,760,239	Total
General Price Level Increases	2%	
Contribution to Fixed Costs from Market (2011)	$ 7,920,698	
Discount Rate (based on Consumer)	5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$ 35,939,495	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$ 42,108,847	
Variable Cost of Operation, per Annum (2003 Price Levels)	$ 29,179,256	
Variable Cost of Operation, per Annum (2011 Price Levels)	$ 34,188,149	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$ 2,889	
Transmission Loss Percentage	0%	

Year	**NVP in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 42,108,847	$ 42,951,024	$ 43,810,044	$ 60,141,803	$ 61,344,639
Variable Costs of Market Operations		$ 34,188,149	$ 34,871,912	$ 35,569,350	$ 48,829,096	$ 49,805,678
Variable Cost per MWh, production of this Unit		$ 83.79	$ 85.46	$ 87.17	$ 119.67	$ 122.06
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 52,919,656	$ 53,678,345	$ 54,452,208	$ 69,164,942	$ 70,248,537
Incremental Fixed Costs of Transmission to Consumers		$ -	$ -	$ -	$ -	$ -
Incremental Transmission Losses		$ -	$ -	$ -	$ -	$ -
Total Annual Costs	**$ 554,492,323**	$ 52,919,656	$ 53,678,345	$ 54,452,208	$ 69,164,942	$ 70,248,537

Simple Cycle Plant - 5 x LM6000PD

Capital Cost, 2005 Dollars	$ 149,000,000	
Fixed Operating Costs, 2005 Dollars	$ 900,000	
BUILT OUTSIDE YORK REGION		
Contribution to Fixed Costs from Market (2002-2004 Prices)	$ 3,133	per MW per month
Plant Capacity	195	MW
Annual Production	459,323	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$ 7,330,594	Total
General Price Level Increases	2%	
Contribution to Fixed Costs from Market (2011)	$ 8,588,959	
Discount Rate (based on Consumer)	5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$ 39,298,411	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$ 46,044,352	
Variable Cost of Operation, per Annum (2003 Price Levels)	$ 31,967,817	
Variable Cost of Operation, per Annum (2011 Price Levels)	$ 37,455,393	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$ 3,133	
Loss Percentage	7%	

Year	**NPV in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 46,044,352	$ 46,965,239	$ 47,904,544	$ 65,762,674	$ 67,077,927
Variable Costs of Market Operations		$ 37,455,393	$ 38,204,501	$ 38,968,591	$ 53,495,525	$ 54,565,435
Variable Cost per MWh, production of this Unit		$ 81.54	$ 83.18	$ 84.84	$ 116.47	$ 118.80
Variable Cost of Production, Same Output as Unit in Northern York Region		$ 33,273,364	$ 33,938,832	$ 34,617,608	$ 47,522,558	$ 48,473,009
Transmission Loss Adjustment		$ 2,329,136	$ 2,375,718	$ 2,423,233	$ 3,326,579	$ 3,393,111
Total Variable Cost of Energy, Delivered to Northern York Region		$ 35,602,500	$ 36,314,550	$ 37,040,841	$ 50,849,137	$ 51,866,120
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 54,334,007	$ 55,120,983	$ 55,923,699	$ 71,184,984	$ 72,308,979
Incremental Price of Transmission to Consumers		$ 2,904,805	$ 2,848,373	$ 2,791,942	$ 1,889,037	$ 1,832,606
Total Annual Cost	**$ 592,836,197**	$ 57,238,812	$ 57,969,356	$ 58,715,640	$ 73,074,021	$ 74,141,585
Present Value of Saving to Consumers From Northern York Region Generation over 20 Years (at 2005 Levels)	**$ 38,343,875**					

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Simple Cycle

2 x GE PG7241FA

Capital Cost, 2005 Dollars	$	147,000,000
Fixed Operating Costs, 2005 Dollars	$	900,000

BUILT IN NORTHERN YORK REGION

Contribution to Fixed Costs from Market (2002-2004 Prices)	$	2,237	per MW per month
Plant Capacity		297	MW
Annual Production		438,818	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	7,972,770	Total
General Price Level Increases		2%	
Contribution to Fixed Costs from Market (2011)	$	9,341,371	
Discount Rate (based on Consumer)		5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$	41,565,151	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$	48,700,200	
Variable Cost of Operation, per Annum (2003 Price Levels)	$	33,592,381	
Variable Cost of Operation, per Annum (2011 Price Levels)	$	39,358,829	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$	2,237	
Transmission Loss Percentage		0%	

Year	**NVP in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 48,700,200	$ 49,674,204	$ 50,667,688	$ 69,555,877	$ 70,946,995
Variable Costs of Market Operations		$ 39,358,829	$ 40,146,005	$ 40,948,926	$ 56,214,100	$ 57,338,382
Variable Cost per MWh, production of this Unit		$ 89.69	$ 91.49	$ 93.32	$ 128.10	$ 130.67
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 58,090,336	$ 58,952,439	$ 59,831,783	$ 76,549,946	$ 77,781,241
Incremental Fixed Costs of Transmission to Consumers		$ -	$ -	$ -	$ -	$ -
Incremental Transmission Losses		$ -	$ -	$ -	$ -	$ -
Total Annual Costs	**$ 611,077,908**	$ 58,090,336	$ 58,952,439	$ 59,831,783	$ 76,549,946	$ 77,781,241

2 x GE PG7241FA

Capital Cost, 2005 Dollars	$	147,000,000
Fixed Operating Costs, 2005 Dollars	$	900,000

BUILT OUTSIDE YORK REGION

Contribution to Fixed Costs from Market (2002-2004 Prices)	$	2,469	per MW per month
Plant Capacity		297	MW
Annual Production		507,870	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	8,800,009	Total
General Price Level Increases		2%	
Contribution to Fixed Costs from Market (2011)	$	10,310,613	
Discount Rate (based on Consumer)		5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$	46,557,527	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$	54,549,563	
Variable Cost of Operation, per Annum (2003 Price Levels)	$	37,757,518	
Variable Cost of Operation, per Annum (2011 Price Levels)	$	44,238,950	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$	2,469	
Loss Percentage		7%	

Year	**NPV in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 54,549,563	$ 55,640,554	$ 56,753,366	$ 77,910,209	$ 79,468,413
Variable Costs of Market Operations		$ 44,238,950	$ 45,123,729	$ 46,026,204	$ 63,184,115	$ 64,447,797
Variable Cost per MWh, production of this Unit		$ 87.11	$ 88.85	$ 90.63	$ 124.41	$ 126.90
Variable Cost of Production, Same Output as Unit in Northern York Region		$ 38,224,005	$ 38,988,485	$ 39,768,255	$ 54,593,292	$ 55,685,158
Transmission Loss Adjustment		$ 2,675,680	$ 2,729,194	$ 2,783,778	$ 3,821,530	$ 3,897,961
Total Variable Cost of Energy, Delivered to Northern York Region		$ 40,899,686	$ 41,717,679	$ 42,552,033	$ 58,414,823	$ 59,583,119
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 59,631,193	$ 60,524,113	$ 61,434,891	$ 78,750,669	$ 80,025,978
Incremental Price of Transmission to Consumers		$ 2,904,805	$ 2,848,373	$ 2,791,942	$ 1,889,037	$ 1,832,606
Total Annual Cost	**$ 650,806,206**	$ 62,535,997	$ 63,372,486	$ 64,226,832	$ 80,639,706	$ 81,858,584

Present Value of Saving to Consumers From Northern York Region Generation over 20 Years (at 2005 Levels) **$ 39,728,298**

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Combined Cycle
GE 7241FA 2x1

Capital Cost, 2005 Dollars	$	450,000,000	
Fixed Operating Costs, 2005 Dollars	$	7,860,000	
BUILT IN NORTHERN YORK REGION			
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	7,960	per MW per month
Plant Capacity		524	MW
Annual Production		2,405,684	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	50,053,698	Total
General Price Level Increases		2%	
Contribution to Fixed Costs from Market (2011)	$	58,645,884	
Discount Rate (based on Consumer)		5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$	171,933,730	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$	201,447,767	
Variable Cost of Operation, per Annum (2003 Price Levels)	$	121,880,032	
Variable Cost of Operation, per Annum (2011 Price Levels)	$	142,801,883	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$	7,960	
Transmission Loss Percentage		0%	

Year	**NVP in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 201,447,767	$ 205,476,723	$ 209,586,257	$ 287,717,018	$ 293,471,358
Variable Costs of Market Operations		$ 142,801,883	$ 145,657,921	$ 148,571,079	$ 203,956,254	$ 208,035,379
Variable Cost per MWh, production of this Unit		$ 59.36	$ 60.55	$ 61.76	$ 84.78	$ 86.48
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 161,533,390	$ 164,464,354	$ 167,453,937	$ 224,292,100	$ 228,478,238
Incremental Fixed Costs of Transmission to Consumers		$ -	$ -	$ -	$ -	$ -
Incremental Transmission Losses		$ -	$ -	$ -	$ -	$ -
Total Annual Costs	**$ 1,743,112,004**	$ 161,533,390	$ 164,464,354	$ 167,453,937	$ 224,292,100	$ 228,478,238

GE 7241FA 2x1

Capital Cost, 2005 Dollars	$	450,000,000	
Fixed Operating Costs, 2005 Dollars	$	7,860,000	
BUILT OUTSIDE YORK REGION			
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	8,435	per MW per month
Plant Capacity		524	MW
Annual Production		2,475,114	MWh
Contribution to Fixed Costs from Market (2002-2004 Prices)	$	53,037,983	Total
General Price Level Increases		2%	
Contribution to Fixed Costs from Market (2011)	$	62,142,451	
Discount Rate (based on Consumer)		5%	
Gross Annual Generator Revenues from Electricity Market (2003 Price Levels)	$	175,190,953	
Gross Annual Generator Revenues from Electricity Market (2011 Price Levels)	$	205,264,124	
Variable Cost of Operation, per Annum (2003 Price Levels)	$	122,152,970	
Variable Cost of Operation, per Annum (2011 Price Levels)	$	143,121,673	
Verification of Margin from Market Operations 2003 Price Levels, per MW per Mo.	$	8,435	
Loss Percentage		7%	

Year	**NPV in 2005**	**2011**	**2012**	**2013**	**2029**	**2030**
Gross Generator Revenues from Electricity Market		$ 205,264,124	$ 209,369,406	$ 213,556,794	$ 293,167,714	$ 299,031,069
Variable Costs of Market Operations		$ 143,121,673	$ 145,984,107	$ 148,903,789	$ 204,412,992	$ 208,501,252
Variable Cost per MWh, production of this Unit		$ 57.82	$ 58.98	$ 60.16	$ 82.59	$ 84.24
Variable Cost of Production, Same Output as Unit in Northern York Region		$ 139,106,934	$ 141,889,072	$ 144,726,854	$ 198,678,956	$ 202,652,535
Transmission Loss Adjustment		$ 9,737,485	$ 9,932,235	$ 10,130,880	$ 13,907,527	$ 14,185,677
Total Variable Cost of Energy, Delivered to Northern York Region		$ 148,844,419	$ 151,821,307	$ 154,857,734	$ 212,586,483	$ 216,838,213
Amount Required for Generator to Recover Capital Costs (80% Levelized)		$ 18,731,507	$ 18,806,433	$ 18,882,858	$ 20,335,847	$ 20,442,859
Total Incremental Costs to Ontario Consumers Resulting from this Generation		$ 167,575,926	$ 170,627,740	$ 173,740,591	$ 232,922,330	$ 237,281,072
Incremental Price of Transmission to Consumers		$ 2,904,805	$ 2,848,373	$ 2,791,942	$ 1,889,037	$ 1,832,606
Total Annual Cost	**$ 1,832,104,645**	$ 170,480,731	$ 173,476,114	$ 176,532,533	$ 234,811,367	$ 239,113,678

Present Value of Saving to Consumers From Northern York Region Generation over 20 Years (at 2005 Levels)	**$**	**88,992,641**

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